Response to Comment in Letter 11 from
Gary Russell, Gerald Metzger, Michael Murphy, and Al Saab,
Whatcom County Fire District No. 7

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

Responses to Comments in Letter 12 from Arne R. Cleveland, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. You are correct. Analyses performed to evaluate impacts on ambient $PM_{2.5}$ concentrations resulting from project emissions have conservatively assumed that all particulate matter emitted is 2.5 microns or less in diameter.

2. The U.S. Environmental Protection Agency has established National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$. These standards, which are codified in Chapter 40, Section 50.7 of the Code of Federal Regulations (CFR), were established to protect human and environmental health against impacts associated with this pollutant. However, other than the NAAQS for Significant Impact Levels, incremental consumption standards have not yet been established in federal regulation (40 CFR 52.21).

   To assess the impacts of the $PM_{2.5}$ emissions on the NAAQS, the U.S. EPA allows PM_{10} to be used as a surrogate because there is no incremental standard for $PM_{2.5}$ established in 40 CFR 52.21. The Applicant has demonstrated that the project's PM_{10} emissions would be below the Significant Impact Level thresholds and would therefore not cause or contribute to a violation of the NAAQS for PM_{10}. Maximum ambient air concentrations of $PM_{2.5}$ that would result from the project are below the NAAQS established for $PM_{2.5}$, as shown in Table 3.2-11 of the Final EIS

3. As required by state and federal regulations under the Prevention of Significant Deterioration (PSD) review, the Applicant modeled project emissions to determine whether or not impacts on ambient air quality concentrations would exceed the Significant Impact Levels established by EPA. Under PSD regulations, only facilities with impacts that exceed Significant Impact Levels are required to include the impacts of other facilities within the modeling zone. The modeling demonstrated that the impacts of the project would be less than EPA's Significant Impact Levels. In fact, the Draft EIS determined that the project would not have any adverse impacts on ambient air quality in the project vicinity and would comply with all Washington State and national ambient air quality standards.

   The Applicant has, however, assessed the sum of the project emissions with existing ambient background levels for criteria pollutants regulated under the PSD program. These data were presented in the Draft EIS in Table 3.2-11 for U.S. locations, and Tables 3.2-15 and 3.2-16 for Canadian locations.

   In addition to the analyses performed under the PSD program, the combined impacts of the BP Cherry Point Cogeneration Project and the Sumas Energy 2 Generation Facility were conservatively evaluated. This analysis is included in Section 3.2 of the Final EIS.

4. As described in Section 3.9 Noise, of the Draft EIS, there would be no perceptible increase in noise at any of the studied receptor locations surrounding the facility.

5. As noted in Section 3.2 Air Quality in the Final EIS, the combined background and predicted concentrations for all criteria pollutants analyzed in the local area are less than the most stringent air quality standards. Section 3.9 Noise in the Draft EIS indicates there would be no perceptible increase in noise at any of the receptor locations surrounding the facility, including Birch Bay State Park. Also, please refer to General Response A for a description of alternative site analysis and an evaluation of the size of the proposed cogeneration facility.

Responses to Comments in Letter 13 from Bill Henshaw, Bellingham Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. The employment benefits noted are correct. Under minimal water demand conditions and with Alcoa Intalco Works in operation, the cogeneration plant would reduce withdrawals from the Nooksack River by more than 700,000 gallons per day.

Responses to Comments in Letter 14 from James Randles, Director, Northwest Air Pollution Authority

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The cited reference of BP 2002 is provided in Chapter 4 on page 4-2 of the Draft EIS. The reference is as follows: BP West Coast Products, LLC. June 2002 (including April 2003 revisions). *BP Cherry Point Cogeneration Project, Application for Site Certification*. Application No. 2002-01. Part I, Compliance Summary; Part II, Environmental Report; and Part III, Technical Appendices. Prepared by Golder Associates, Inc. for the Energy Facility Site Evaluation Council. Olympia, Wash.

2. The annual emission rates for toxic VOCs were identified in Table 3.2-13 of the Final EIS. These total 6,416.8 lbs/year and represent 7.6% of total facility VOC emissions.

3. Nitric oxide emissions, NO, were included in the evaluation of all nitrogen oxide (NO_x) emissions. The maximum modeled concentration of NO_x from the facility as a whole is 2 $\mu g/m^3$ on a 24-hour average, which is much lower than the 100 $\mu g/m^3$ Acceptable Source Impact Level.

Responses to Comments in Letter 15 from Rob Pochert, Executive Director, Bellingham Whatcom, Economic Development Council

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

Response to Comment in Letter 16 from Preston Sleeger, Regional Environmental Officer, United States Department of the Interior

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

Responses to Comments in Letter 17 from Gerald Steel, Attorney-at-Law, Seattle

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The design of the Applicant's project avoids many potentially adverse environmental impacts. Potential impacts that could not be avoided were evaluated and, with proposed mitigation, the resulting impacts are not considered significant. Assuming the project is approved, the Applicant will carry out stipulated mitigation measures contained in the Site Certification Agreement as well as conditions (general and specific) in the federal permits to be obtained by the Applicant. EFSEC and federal regulatory agencies will monitor the success of the mitigation designed and carried out by the Applicant.

2. Thank you for your comment. Recent research and analyses into the effects of global warming have identified global and regional impacts that may occur. There is uncertainty as to the time when such effects will be measurable and the magnitude of the impacts that may occur. Because of the nature of the models used to predict the effects of greenhouse gas (GHG) emissions on global warming and the global nature of the effects, there is insufficient information to predict the actual impacts resulting from the project's emissions alone. Additional information regarding GHG and global warming has been added to Sections 1.8.1 and 3.2.5 of the Final EIS.

3. As noted in Section 3.6 of the Draft EIS, the cogeneration facility (and in fact the entire project) is located on land zoned for industrial land uses; it therefore does not meet the federal definition for prime agricultural land. While the soils present on the site are those identified in Whatcom County Code 20.38 as "Agriculture Protection Overlay Soils," the code further states the provisions apply only to rural, not industrial, zoning designations.

4. Please refer to Response 3 of this letter. The project will burn a clean fuel, natural gas, and the resulting emissions will be dispersed over a wide area. Only a small fraction of the pollutants would remain in the project vicinity. When compared to coal and diesel fuel, natural gas combustion emits much lower quantities of criteria and toxic pollutants and is not a significant source of acid rain. Project emissions will be minimized through the use of Best Available Control Technology as explained in Section 3.2 of the Final EIS.

5. Water removed from the Nooksack River for use at Alcoa Intalco Works is discharged to the Strait of Georgia. If Alcoa Intalco Works is not in operation, the water that would have been transferred to the cogeneration facility for reuse would instead be delivered directly to the BP Cherry Point Refinery. There would be no increase in water withdrawn from the Nooksack River. All water used by the cogeneration facility would either evaporate in the cooling tower or be treated at the refinery's wastewater treatment facility and discharged to the Strait of Georgia. The water will not be distributed to the local microsystem or agricultural lands.

6. In accordance with the requirements of the Prevention of Significant Deterioration (PSD) program, the Applicant used the CALPUFF model to determine visibility in Class I areas in the U.S. PM_{10}, NO_X, and SO_2 were modeled with chemical transformations of secondary pollutants such as ammonia nitrate and ammonia sulfate, and the results were combined to calculate a visibility coefficient. The results were then compared with background data to calculate the percentage of visibility change.

Table 3.2-12 of the Final EIS shows that the project emissions (excluding any emission reductions from removal of refinery boilers) predict a 5% visibility change for one day at one Class I area (Olympic National Park). Federal guidelines for determining the criteria used to define a significant impact on regional visibility from emissions at new air pollutant sources were recently published by the Federal Land Managers' Air Quality Related Values Workgroup in its Phase One Report, published by the U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service in December 2001. According to the federal land mangers responsible for protecting air quality in Class I areas, a 5% change in extinction (a coefficient used to quantify how pollutants in the atmosphere reduce visual range) indicates a "just perceptible" change to a landscape and a 10% change is considered a significant incremental impact. The National Park land managers were consulted about the perceptible change caused by the project, and they consider it acceptable (Morse 2003).

The Draft EIS assesses the cumulative impact on visibility from construction of the BP Cherry Point Cogeneration Project and other proposed power plants in the Pacific Northwest. Phase II of Bonneville's regional impact analysis addressed the visibility impacts of the BP Cherry Point Cogeneration Project in a "most likely" scenario of the Phase II baseline group. In other words, if all projects included in that baseline group were built, some impacts on visibility would most likely occur, as explained in detail in the Draft EIS, but visibility would not be permanently cut off.

<u>Exhibit 1</u>

1(1) The energy market in the Pacific Northwest has changed in the last 18 to 24 months; however, long-term regional energy needs require that additional facilities be constructed to meet regional demand within the next 10 years. Market forces will control which of the proposed facilities actually move forward to construction and operation once they have received environmental and other approvals.

The Northwest Power Pool comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. From 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6% and 1.7%, respectively. With a large percentage of hydro-generation in the region, the ability to meet peak demand is expected to be adequate for the next 10 years. Capacity margins for this winter peaking area range between 23.4% and 29.6% for the next 10 years.

As shown in the following table, a recent survey of large combustion turbine facility projects in the Pacific Northwest indicates that over 11,000 MW of large natural gas turbine proposals have been cancelled, denied permit, or delayed indefinitely, approximately 4,750 MW have been approved but have not started construction, and approximately 5,500 MW are undergoing review. In its most recent 10-year coordinated plan summary, the Western Electricity Coordinating Council projects that reserves will be adequate throughout the region through 2012, but only if 32,300 MW of new generation are brought on line when needed. Droughts in the Pacific Northwest may substantially reduce the availability of electricity for export from the region, and capacity becomes highly dependent on northwest hydroelectric conditions after 2008. The net power increase is projected to be 12,300 MW of committed resources and 20,000 MW of uncommitted resources.

The 546 MW for the Hermiston Power Project reflect the numbers presented in the 2001 Phase II study completed by Bonneville.

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Operating Facilities						
Evander Andrews (Mt Home)	Elmore	Idaho	Gas Turbine	90	10/1/2001	Idaho Power Company
Rathdrum	Kootenai	Idaho		270	9/1/2001	Avista/Cogentrix
Exxon I	Yellowstone	Montana	Gas Turbine	20	4/1/2001	Exxon
Albany Cogeneration	Linn	Oregon	Cogen	85	7/1/2000	Williamette
Beaver GT	Columbia	Oregon	Gas Turbine	24	7/1/2001	Portland General Electric
Coyote Springs II	Morrow	Oregon	Combined	280	7/1/2003	Avista/Mirant
Hermiston	Umatilla	Oregon	Combined	530	8/20/2002	Calpine
Hermiston Peaking	Umatilla	Oregon	Combined	100	8/20/2002	Calpine
Klamath Falls Cogeneration	Klamath	Oregon	Combined	500	7/1/2001	PacifiCorp
Klamath Falls Expansion	Klamath	Oregon	Gas Turbine	100	6/1/2002	Pacific Klamath Energy
Morrow Power GT	Morrow	Oregon		25	8/1/2002	Morrow Power
SP Newsprint Cogen	Yamhill	Oregon	Combined	130	7/1/2003	SP Newsprint
Benton PUD (Finley)	Skagit	Washington	Gas Turbine	27	12/20/2001	Benton PUD
Big Hanaford (Centralia)	Lewis	Washington		248	7/1/2002	TransAlta
Boulder Park	Spokane	Washington		25	4/1/2002	Avista
BP Cherry Point GTs	Whatcom	Washington	Gas Turbine	73	9/1/2001	Cherry Point Refinery
Chehalis Generation	Lewis	Washington	Combined	520	10/1/2003	Tractebel
Equilon GTs	Skagit	Washington	Gas Turbine	38	1/1/2002	Equilon Enterprises

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Frederickson	Pierce	Washington		249	8/1/2002	EPCOR & Puget Sound Energy
Fredonia Addition	Skagit	Washington	Gas Turbine	106	8/1/2001	Puget Sound Energy
Pasco GTs	Franklin	Washington	Gas Turbine	44	6/30/2002	Franklin/Grays Harbor PUD
Pierce Power	Pierce	Washington	Gas Turbine	154	9/1/2001	TransAlta
SUBTOTAL				3,638		
Facilities Under Construction						
Frederickson Expansion	Pierce	Washington		25	6/1/2005	EPCOR & Puget Sound Energy
SUBTOTAL				25		
Regulatory Approval Received						
Bennett Mountain		Idaho	Peaker[1]	162	7/1/2005	Idaho Power
Silver Bow	Silver Bow	Montana	Combined	500	1/1/2011	Continental Energy Services
Port Westward	Columbia	Oregon	Combined	650	4/1/2006	Portland General Electric
Summit/Westward	Columbia	Oregon	Combined	520	4/1/2006	Westward Energy LLC
Umatilla Generation Project	Umatilla	Oregon	Combined	610	3/31/2008	PG&E Natl Energy
Frederickson Power 2	Pierce	Washington	Combined	300	1/1/2011	EPCOR & Puget Sound Energy
Sumas 2 Generating Facility	Whatcom	Washington	Combined	660	1/1/2011	National Energy
Wallula	Walla Walla	Washington	Combined	1,350	1/1/2011	Newport Generation
SUBTOTAL				4,752		
Under Review						
Rathdrum GT to CC Conversion	Kootenai	Idaho	Combined	90	9/1/2005	Avista
Basin Creek	Silver Bow	Montana	Reciprocating Engines	48	1/1/2011	Basin Creek Power
COB Energy Facility	Klamath	Oregon	Combined	1,150	6/1/2005	Peoples Energy
Klamath Generating Facility	Klamath	Oregon	Combined	500	1/1/2011	PacifiCorp Power Marketing
Turner	Marion	Oregon	Combined	620	1/1/2011	Calpine
Wanapa Energy Center	Umatilla	Oregon	Combined	1,230	1/1/2011	Eugene Water & Elec
West Cascade Energy Facility	Lane	Oregon		600	12/31/2007	Black Hills Corp
BP Cherry Point	Whatcom	Washington	Combined	720	6/1/2006	Cherry Point Refinery

1 A facility that operates during peak power demands.

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Plymouth Generating Facility	Benton	Washington	Combined	306	1/1/2011	Plymouth Energy
Tahoma Energy Center	Pierce	Washington	Combined	270	1/1/2011	Calpine
SUBTOTAL				5,534		
Cancelled, Denied Permit, or Delayed Indefinitely						
Garnet Energy Facility I	Canyon	Idaho	Combined	273		Ida-West
Garnet Energy Facility II	Canyon	Idaho	Combined	262		Ida-West
Kootenai	Kootenai	Idaho	Combined	1,300		Newport Generation
Mountain Home (PDA)	Elmore	Idaho	Gas Turbine	104		Power Development Association
Rathdrum II	Kootenai	Idaho	Combined	500		Cogentrix
Montana First Megawatts	Cascade	Montana	Combined	250		Northwestern Corp
Coburg	Lane	Oregon	Combined	605		Coburg Power
Columbia River Energy	Columbia	Oregon	GT	44		Columbia River Energy
Grizzly Power Project	Jefferson	Oregon	Combined	980		Cogentrix
Morrow	Morrow	Oregon	Combined	550		PG&E Natl Energy
Pope & Talbot Cogen (Halsey)	Linn	Oregon	Gas Turbine	93		Oregon Energy
St Helens Cogen	Columbia	Oregon	Combined	141		Oregon Energy
West Linn Paper	Clackamas	Oregon	Combined	94		West Linn Paper
Cowlitz Cogeneration project	Cowlitz	Washington	Combined	395		Weyerhaeuser
Everett Delta 1 (Preston Point)	Snohomish	Washington		496		FPL Energy
Goldendale	Klickitat	Washington	Combined	248		Calpine
Goldendale NW (The Cliffs)	Klickitat	Washington	Gas Turbine	190		Goldendale NW Alum
Longview Power Station	Cowlitz	Washington	Combined	245		Enron
Mercer Ranch	Benton	Washington	Combined	850		Cogentrix
Mint Farm	Cowlitz	Washington	Combined	286		Mirant
NW Regional Power (Creston)	Lincoln	Washington	Combined	838		Northwest Power Ent
Satsop (Grays Harbor Phase l)	Mason	Washington	Combined	650		Duke Energy NA
Satsop ll (Grays Harbor Phase ll)	Mason	Washington	Combined	600		Duke Energy NA
Sedro-Wooley	Skagit	Washington	Gas Turbine	83		Tollhouse Energy
Starbuck	Columbia	Washington	Combined	1,200		PPL Global
SUBTOTAL				11,277		

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Press Release Only						
Black Hills	Hill	Montana		80		Black Hills Power
Blackfeet	Glacier	Montana		160		Adair
Indigenous Global		Washington		1,000		Indigenous Global
Port Frederickson Industrial	Pierce	Washington		324		Morgan Stanley
SUBTOTAL				1,564		
GRAND TOTAL				**26,790**		

Source: Database of Proposed Generation within the Western Electricity Coordinating Council, February 2, 2004.

1(2) As indicated in the alternatives analysis (see Section 2.4 and Appendix A of the Draft EIS), the Applicant considered the construction of a smaller facility. However, a smaller facility would not meet the requirements of reliability for steam delivery to the refinery and cost-effective power productions. Please refer to General Response A for additional information regarding an evaluation of facility size.

1(3) SCONOx control technology has been demonstrated on smaller combustion turbines (approximately 1 to 40 MW) in California and Massachusetts. To date, however, there have not been any SCONOx systems installed on large combustion turbine applications such as that proposed for this project. Additional technical uncertainties regarding the applicability of SCONOx technology to “F” class turbines have recently been raised by other permitting agencies. On May 30, 2001, the U.S. EPA Environmental Appeals Board and the California Energy Commission issued simultaneous rulings on another project; both refused to overturn a Best Available Control Technology (BACT) decision by the Shasta County Department of Resource Management Air Quality Management District that the SCONOx technology is not technically feasible for turbines of the size being considered for the proposed BP Cherry Point Cogeneration Project. In its BACT decision, the District said that several operational requirements associated with the SCONOx technology make it impractical for use as an emission control technology for “F” class turbines. It stated that all routine operating conditions were not covered in the SCONOx technology guarantee and that the guarantee would be void if water came into contact with the catalyst. Selective catalytic reduction (SCR) was the alternative BACT technology that was selected.

While it is true that the SCR system can use aqueous ammonia to control NO_x, anhydrous ammonia is proposed for economic reasons. Aqueous ammonia is approximately 20% ammonia, which would require additional quantities of ammonia to be delivered to the cogeneration facility, requiring more or larger storage tanks and additional internal piping. Because the BP Refinery currently transports, uses, stores, and internally transfers anhydrous ammonia—all within local, state, and federal guidelines—the Applicant chooses to use anhydrous ammonia in the SCR.

1(4) A discussion of the handling and storage of ammonia is presented in Sections 2.2.2 and 3.16.2 of the Draft EIS. As described in Section 3.15.2 of the Draft EIS, trucks would deliver anhydrous ammonia to the cogeneration facility approximately twice a month. Currently, ammonia is delivered to the refinery twice a year. It is anticipated that the additional ammonia needed for the SCR would be supplied by local suppliers and delivery trucks would use the same routes as used today. All ammonia delivery trucks would have to follow appropriate federal, state, and local permitting requirements. In addition, the revised Risk Management Plan required by the EPA would identify and describe actions to be taken by the refinery and public emergency response personnel in case of an accidental spill or traffic accident in which ammonia is released into the environment.

1(5) The models used for estimating the amount of secondary particulate formed did not cap the amount of ammonia available for reaction. It is assumed that sufficient ammonia was present in the airshed for the maximum amount of secondary particulate to be formed from NO_x and SO_2 emissions. The source of ammonia in the airshed (i.e., ammonia from existing industrial or agricultural sources, or ammonia from the project) did not influence the amount of secondary particulate formed.

Ammonia is recognized as a hazardous air pollutant as defined under WAC 173-460-150, and the impacts of ammonia emissions were analyzed in accordance with the requirements of Chapter 173-460 WAC. The maximum predicted concentrations were modeled and compared against the corresponding Acceptable Source Impact Level (ASIL). The ASILs are health-protective thresholds well below concentrations that are known to cause harm to human health and the environment. If concentrations are below the ASILs, no additional study is required by state or federal law. If concentrations exceed the ASILs, a “second tier” health assessment must be performed to determine if the emissions and resulting ambient concentrations will threaten human health or increase human health risks. The second tier analysis may be required to consider the impact of other existing sources of the compound on potential health risks. Because no ASILs were exceeded, additional analysis of other ammonia sources is not necessary.

1(6) Please refer to Response 1(3) of this letter for a discussion of SCONOx technology. This comment refers to a new generation of low NO_x burners appropriate for power plants that can reportedly lower NO_x emissions to below 5 ppm without causing ammonia emissions. The authors of the Final EIS assume that this improved technology is being proposed instead of the dry low NO_x burners proposed by the Applicant. Without more specific detail regarding the manufacturer and usage specifications of the <5 ppm burners, it is not possible to assess whether such technology could be applied to this size and type of generation facility. The dry low NO_x technology being proposed has been commercially available and proven effective for GE 7FA turbines. BACT for this type of project also requires NO_x emission reductions to be 2.5 ppm or lower.

1(7) Atmospheric reactions that convert ammonia, NO_x, and SO_x to secondary particulate (ammonium nitrate and ammonium sulfate) take place outside of the exhaust stacks hours to days after the NO_x and SO_x have been emitted from the facility. The reactions are controlled by time, temperature, humidity, sunlight, concentration of the reactants, and atmospheric mixing. Secondary particulate is therefore formed at great distances from the source of the pollutants.

Impacts of nitrate and sulfate deposition on soils must be evaluated in Class I areas. This evaluation was performed and results were within acceptable criteria, according to the federal land managers (see Section 3.2.3 in the Final EIS).

Neither guidelines nor thresholds for impacts from deposition to soils have been established for Class II areas. Nevertheless, the Applicant modeled the deposition rates near the project site and determined that maximum rates occur on the northern side of the facility boundary. The maximum deposition rates modeled were 167 and 187 grams/hectare/year for ammonium sulfate and ammonium nitrate, respectively. In the absence of any guidelines or regulatory criteria for the assessment of impacts, this deposition rate was compared to typical nitrogen fertilizer rates in agricultural soils. Agricultural spreading of fertilizer can vary widely depending on soil or crop type. Nitrogen is typically spread on agricultural lands at a rate of 250 pounds/acre/year. The maximum deposition rate for the project represents 0.17 pound/acre/year, which is a small amount compared to that added by agricultural soil amendment.

1(8) Please refer to Response 1(4) of this letter.

1(9) Please refer to Responses 1(3) and 1(4) of this letter.

1(10) Please refer to Response 1(4) and Section 3.16.2 of the Draft EIS regarding the transportation, handling, storage, and potential impacts resulting from a release of ammonia.

1(11) Section 3.2.1 of the Draft EIS has been revised to reflect that the proposed cogeneration facility would be subject to Title III requirements. Pertinent regulations addressing this issue include: Accidental Release Prevention and Risk Management Plan, 40 CFR 68, Chapter 90.56 RCW and Hazardous Substances/Worker Community Right to Know Act, Chapters 70.105, 70.136, and 49.70 RCW.

1(12) Section 2.4.3 of the Final EIS has been updated to include additional information about the Applicant's choice of a wet cooling system versus a dry cooling system.

In choosing wet cooling for the project, the Applicant considered the following factors: (1) availability of water supply; (2) footprint required for the cooling system; (3) impacts on project power generation efficiency; (4) impacts on visual resources; (5) noise emissions from the facility; and (6) capital cost of the cooling system.

As explained in Section 2.4.3 of the Final EIS, dry cooling was originally considered because of the restricted availability of local certificated water resources. Instead, an agreement was established among the Applicant, Alcoa Intalco Works, and the Whatcom PUD allowing once-through water used for cooling at Alcoa Intalco Works to be used as inlet water in the wet cooling system for the project. At times when Alcoa Intalco Works is not in operation, the PUD will supply the water directly to the project. It should be noted that if Alcoa Intalco Works is not in operation, the average amount of water supplied to the project would be less than the water consumed by Alcoa Intalco Works and reused by the project.

The Applicant is choosing the wet cooling system because it would require a smaller footprint for the equipment, would have less visual impact, would produce less ambient noise, would not incur a 1.6% loss in power generation efficiency, and would cost less (one-third that of a dry cooling system).

The commenter presents an extensive list of facilities that use cooling systems other than wet cooling. The commenter, however, does not explain the particular circumstances of the facilities that lead to these choices. For example, in the case of the Chehalis Generation Facility, the choice to use air cooling was made partially to avoid the cost of constructing a pipeline to withdraw and carry the water from the Chehalis River and to discharge wastewater to the City of Chehalis' water treatment system rather than to the Chehalis River.

1(13) There is no economic justification for evaluating a zero liquid discharge facility. The BP Refinery has an operating wastewater treatment facility that is capable of treating and disposing of the wastewater from the cogeneration facility. A new and separate treatment plant would not be warranted. Solid waste material from the refinery's treatment system would include small quantities of chemicals in the waste stream from the cogeneration facility; the quantity of solids attributed to the cogeneration facility would be small compared to the material currently disposed of by the refinery.

1(14) The Draft EIS states that the cogeneration facility would generate 190 gpm on average (assuming 15 cycles of concentration in the cooling tower) of non-recyclable process wastewater that would be sent to the BP Refinery's wastewater treatment system. As presented in Table 3.4-4 of the Draft EIS, the estimated concentration of trace metals and other constituents in the cogeneration facility wastewater discharge represents what is anticipated to be present after up to 15 cycles. The Draft EIS includes detailed notes for Table 3.4-4, including the source of the data used to make the concentration calculations. Many of the trace metals presented in the table were not detected. This indicates that if those metals are present in the water from the Nooksack River, they are at concentrations below the values used to derive the concentrated values presented in Table 3.4-4. Therefore, it is not anticipated that concentrating trace metals present in cogeneration facility feedwater (i.e., raw water from the Nooksack River) would produce significant concentrations of potentially toxic materials in the discharge water. Additionally, no radioactive materials will be used at the cogeneration facility, and therefore there is no reason to anticipate the presence of radioactive materials at toxic concentrations in the feedwater or discharge water.

1(15) The ISOM unit (gasoline isomerization or Clean Fuels Project). is being constructed on existing laydown areas within the refinery, not in wetlands; therefore, it is not subject to the jurisdiction of the U.S. Army Corps of Engineers (Corps) under the Clean Water Act.

BP Refinery is proposing to use the Brown Road Materials Storage Area to replace those laydown areas used for the ISOM unit. That area does have wetlands under the jurisdiction of the Corps, and the Corps is reviewing the proposal. The Brown Road Materials Storage Area is located between Alternative Cogeneration Sites 2 and 3 or Alternative Laydown Sites C and D as presented in the revised alternatives analysis (Appendix A) in the Final EIS.

It is correct that the wetland mitigation area for the Brown Road Materials Storage Area is adjacent to CMA 2, one of the wetland mitigation areas for the cogeneration facility.

1(16) Consideration of the impacts of the ISOM project has been incorporated into the analysis of cumulative impacts resulting from the proposed project. The ISOM project would cumulatively, but not significantly, add to air emissions and wetland impacts. The ISOM project is being constructed within the refinery grounds and has no wetland impacts. The Brown Road Materials Storage Area would include wetland mitigation north of Grandview Road and west of the proposed cogeneration facility mitigation areas. Discharge from the Brown Road Materials Storage Area to the wetland mitigation area would be through existing ditches within the proposed cogeneration facility laydown areas. These ditches would not be eliminated by construction of the laydown areas.

The appropriate sections of Chapter 3 have been revised to incorporate this information.

1(17) The Draft EIS states that effluent from the cogeneration facility's oil-water separator would be discharged to a final treatment and detention pond properly sized in accordance with Whatcom County and Ecology requirements, not to ponds in CMA 1. Once treated, stormwater would be routed to the wetland mitigation area.

1(18) Please refer to Response 1(16) of this letter.

1(19) Thank you for your comment. The Applicant proposes to tap into the Ferndale Natural Gas Pipeline that runs between the refinery and the proposed location of the cogeneration facility. The Ferndale Pipeline, owned and operated by BP Pipeline, Inc., originates in Sumas, Washington, near the Canadian border. The pipeline extends 30.7 miles to Ferndale. The pipeline is not dedicated or devoted to any public use but is used exclusively to transport natural gas for consumption as fuel at BP's Cherry Point Refinery and Alcoa Intalco Works. The maximum allowable operating pressure of 550 pounds per square inch gauge (psig) was authorized by the Washington Utilities and Transportation Commission (WUTC) in a waiver at the time the Ferndale Pipeline was commissioned in 1990. The pipeline was designed for Class 4 locations (a location where buildings with four or more stories aboveground are prevalent) per CFR 192 (DOT regulations) and to operate at a maximum allowable operating pressure of 1,105 psig. The pipeline operates at 550 psig.

There have been no leaks or operational failures on the Ferndale Pipeline (Walsh, pers. comm., 2004). The WUTC pipeline safety inspection staff have performed annual inspections on the pipeline since it was put in use. In March of 2000, BP inspected the pipeline using what is known as a "smart pig." One metal failure was found and repaired; two others were investigated, but no repairs were required.

BP Pipeline, Inc. is required to operate the pipeline according to applicable state and federal safety standards and regulations. Since the pipeline was installed, the regulatory agency with oversight (WUTC) has not raised questions about the pipeline's structural integrity or safety record.

1(20) Please refer to Response 1(19) of this letter.

1(21) If a pipeline incident were to occur inside the refinery boundary, the refinery's emergency response personnel would respond to the emergency. The Applicant has agreed to work with Fire District No. 7 to develop an emergency response protocol, which would be incorporated into mutual aid agreements between the two entities.

1(22) Hydrogen will be stored in pressurized cylinders near the gas turbines as shown in Table 3.16-5 of the Draft EIS. The hydrogen will be used for cooling combustion turbine blades during normal operation. An estimated 605,000 standard cubic feet of hydrogen storage is required. As mentioned in Response 1(21), specific protocols would be followed in using, storing, and transporting hydrogen and other potentially flammable materials.

1(23) State and federal laws require certain hazardous materials to be identified and quantified for local emergency response organizations. The proposed project will continue to comply with all state and federal laws concerning hazardous material transport, use, and storage.

1(24) Regardless of the current supply, demand, and future predicted market characteristics, the use of gas, its cost, and the potential for new gas reserve development or alternatives to gas as an energy source are determined by market forces and not evaluated in this EIS. An attempt to identify potential impacts resulting from further gas development in Canada would be, at best, speculative in nature, and such development would be subject to Canadian environmental review and mitigation by the appropriate Canadian regulatory agencies.

Section 3.8.4 of the Final EIS have been updated to include an analysis of cumulative impacts on regional natural gas supplies.

1(25) Thank you for your comment. Section 3.2.3 of the Final EIS has been revised to include a discussion of secondary formation of particulate matter.

1(26) PM_{10} emissions from the cooling towers will be limited to 7.2 tons per year on a rolling annual average, estimated monthly. Therefore, even though the cogeneration project may be larger than the Goldendale Energy Plant, its annual cooling tower emissions will be similar. The PM_{10} emissions from the cooling tower were included in the consideration of the project's impacts on ambient air quality and other regulated air quality values. It was determined that the project as a whole, including the cooling tower, would not violate ambient air quality standards.

Emissions from the cooling tower are expected to consist of only PM_{10}. These emissions originate from the dissolved solids contained in droplets of cooling water called "drift" that escape in the air stream exiting the cooling tower. Drift eliminators have been incorporated into the tower design to remove as many droplets as practical before the air exits the tower. A high efficiency drift eliminator with a drift rate of 0.001% is proposed for the project. Droplets that exit the tower are expected to land close to this source.

1(27) Section 3.2 of the Draft EIS addressed the formation of secondary particulate. The discussion has, however, been expanded in the Final EIS. Table 3.2-23 of the Final EIS estimates the secondary particulate that could be formed by the project and decreases in secondary particulate emissions as a result of removing the refinery boilers.

The CALPUFF model was used to assess the visibility impacts in Class I areas, as required by the PSD program. CALPUFF takes into account the formation of secondary particulate and the contribution of that particulate on visibility impacts. The federal land managers have indicated that the visibility impacts on Class I areas (see Section 3.2 3 of the Final EIS) are acceptable (Morse 2003).

Section 3.2.3 of the Final EIS has been updated to include a discussion of health impacts of fine particulate, PM_{10}, and $PM_{2.5}$ in particular. The project will not violate PM_{10} and $PM_{2.5}$ National Ambient Air Quality Standards. These standards conservatively protect human health.

1(28) The Department of Ecology, as a contractor to EFSEC, reviewed the Applicant's process wastewater characteristics and proposed treatment protocol. The primary purpose of this technical review was to identify conditions, mitigation measures, and/or wastewater treatment methods needed to meet the state water quality standards that protect marine biota in the receiving water around the refinery discharge. If the project is approved, final project-specific State Waste Discharge and National Pollutant Discharge Elimination System (NPDES) permits would specify the discharge limits of treated process wastewater (including inhibitors) and stormwater from the project. Such limits protect human health and aquatic species.

1(29) The Applicant estimates 0.7 cubic yards per day of spent cellulose filter material will be sent from the cogeneration project to the refinery's non-hazardous waste land farm. The refinery's land farm disposes of 10 to 30 cubic yards per day. Based on the maximum potential rate of generation of spent cellulose waste, the cogeneration project would increase the current land farm disposal rate at the refinery by 2.3% to 7.0%. Hazardous materials would be treated and disposed of at an approved facility.

1(30) The stormwater treatment system will be designed to meet the requirements of Whatcom County and the design standards presented in Ecology's Stormwater Management Manual for Western Washington (2000). Additionally, discharge from the oil-water separator and stormwater treatment pond will be required to meet the conditions of a NPDES and State Waste Discharge permits, which cover all discharge from the cogeneration facility to surface waters. These measures should sufficiently minimize potential impacts of stormwater runoff from the cogeneration facility and would protect all applicable state water quality standards.

1(31) The stormwater collection and treatment system is described in detail in Section 3.4 Water Quality on page 3.4-12 of the Draft EIS. As described, all stormwater runoff from the cogeneration facility, with the exception of stormwater captured in secondary containment structures for outside tanks and chemical storage areas, would be routed to the oil-water separator by the stormwater collection system. Stormwater captured in the secondary containment structures would be analyzed for the presence of fuel and chemical contaminants. If contaminants are detected, this stormwater would be routed to the refinery's treatment system. If contaminants are not detected, this stormwater would be routed to the cogeneration facility's stormwater treatment system, including the oil-water separator. It should be noted that some stormwater in the switchyard area will infiltrate directly into the underlying soil. Additionally, discharge from the oil-water separator and stormwater treatment pond will be required to meet the conditions of a NPDES permit, which covers all discharge from the cogeneration facility to surface waters. These measures should sufficiently minimize impacts of stormwater runoff from the cogeneration facility.

1(32) Biocides will be added to control bacteria in the cooling towers, and thereby prevent the formation of *Legionella* bacteria. A mixture of bleach (15% aqueous solution of sodium hypochlorite) and sodium bromide (40% aqueous solution) will be added to the circulating water in a ratio of 10:1. This is the same biocide formulation that is used in the existing refinery cooling towers. Generally, industrial cooling systems are less prone to bacterial formation because they operate continuously, unlike indoor heating/ventilation/air-conditioning (HVAC) systems, which have caused outbreaks of Legionnaires' disease. Continuous operation keeps the biocides well mixed in the circulating water and reduces stagnant conditions where bacteria can develop and reproduce. This information has been incorporated into Section 3.16 of the Final EIS.

1(33) Because the comment mentions proposed transmission lines "about 3000 feet long" we assume it refers to the 230-kV double circuit line (approximately 0.8 mile long or 4,224 feet) needed to connect with Bonneville's Custer-Intalco Transmission Line No. 2 for integration with the transmission grid. Underground construction of high voltage transmission lines tends to be much more expensive than overhead construction. It is unusual for any utility to use underground construction for 230-kV lines—the few examples cited are exceptions. Reasonable circumstances for constructing transmission lines underground would be marine crossings or dense urban areas. The additional equipment required, such as insulating fluids, high-pressure pumps, and temperature-monitoring equipment, would greatly increase costs. Also, the relative difficulty of maintaining and repairing underground transmission lines makes an underground line less reliable. Regarding the point that the new line would create an avian collision hazard, studies have found that such problems occur only in specific, localized situations where birds in flight must frequently cross a power line within their daily use area (Edison Electric Institute 1994). Although the proposed transmission line would pass through an emergent wetland, a narrow band of black cottonwood, and mixed coniferous/deciduous forest habitat used by some of the birds listed in Table 3.7-1, there is no evidence to indicate the line would intersect a major local flyway. It was also suggested the line would cause significant visual impact and increase human exposure to electromagnetic fields; however, the line would be located on unpopulated land zoned for industrial use and near industrial facilities. Finally, underground construction would cause substantially more ground disturbance than overhead construction. Underground construction is not a reasonable alternative because it offers no environmental advantages to overhead construction in this situation, would be significantly more expensive, and would be less reliable.

1(34) The estimate of pollutant emission reductions from removal of refinery boilers focused only on criteria pollutants. The ammonia emissions from operation of the project were identified in Table 3.2-13 of the Draft EIS. Secondary particulate formed by ammonia, NO_x, and SO_2 emissions was also discussed in Section 3.2 of the Draft EIS. Long range modeling of project emissions, including conversion to secondary particulate (and excluding any reductions from removal of refinery boilers), has shown that the project will not violate any U.S. or Canadian ambient air quality standards or objectives.

We assume that the commenter's statement that the project will emit as much as 1,400 tpy of secondary particulate is based on the analysis performed in the Wallula Power Project Final EIS. The Wallula Final EIS states that, theoretically, 1 ton of ammonia emissions could yield 4.6 tons of secondary particulate as ammonium nitrate. However, the Wallula Final EIS also states that the chemical fate of ammonia emissions from the plant is not well understood, and it is uncertain what fraction of the ammonia would actually react to form ammonium nitrate. As noted in Response 1(5), the Whatcom County/Lower Fraser Valley airshed is already ammonia rich because of existing industrial and agricultural activities; therefore, additional emission of ammonia from the project may not be the controlling factor in secondary particulate formation and the emissions of NO_x and SO_2 would be. Other commenters have also noted that the conversion rates used by the Applicant (much less than the theoretical stated above) could be overestimating the actual conversions.

1(35) To meet the 2005 federal standard for sulfur in gasoline, the Applicant proposes to implement a clean gasoline project at its Cherry Point Refinery in Whatcom County. The project will process light naphtha feedstocks to produce a gasoline blend that has essentially no benzene, olefins, or sulfur, and is higher in octane than its feed. The project will have a naphtha dehexanizer unit; an ISOM Hydrotreater (IHT) that includes a process heater, a naphtha hydroheater, and a BenSat unit; a Penex (isomerization) unit; connections to existing processes and changes in tank services within the refinery; and a new #2 boiler. The cumulative impacts of the ISOM project (gasoline isomerization or Clean Fuels Project) have been included in the appropriate sections of the Final EIS, with air emissions from the ISOM project identified in Section 3.2.

Please refer to Letter 12, Response 3 and Response 1(5) of this letter for an explanation of why cumulative impacts on ambient air quality from both criteria and toxic pollutants are not expected.

1(36) Regarding NO_x reductions mandated by the consent decree (*United States v BP Exploration and Oil Co.*, 2:96 CV 095 RL)[1], BP West Coast Products, LLC maintains a list of emissions sources at the refinery that are targeted for removal to comply with the emissions reductions mandated by the consent decree. According to the requirements of the decree, the list is updated annually; however, equipment may be added or removed as long as the emission reduction targets are met. At the time of Final EIS preparation, the refinery boilers were on the list of equipment targeted to be removed at the refinery to comply with the decree. Emission reduction credits (ERCs) are not being sought for the removal of the boilers. Therefore, if the boilers are still on the mandated equipment removal list when the proposed project is constructed, their removal can partially fulfill the requirements of the consent decree.

Consideration of the contribution of the BP Refinery emissions to the past non-attainment status of the Seattle area or to ambient air quality in British Columbia is outside the scope of this Final EIS.

1(37) The emission of toxic air pollutants was summarized in Table 3.2-13 of the Draft EIS. Table 3.2-13 showed all toxics for which emission increases are expected. The Applicant does not seek credits for decreases in toxic air pollutants or criteria emissions resulting from removal of the boilers at the refinery. The Applicant is not seeking to trade emissions of toxic air pollutants from the project, which underwent the full review required by WAC 173-460 without any credits for refinery reductions being taken into account. The commenter is correct that removal of the refinery boilers can also lead to a reduction in toxic air pollutant emissions. This would represent an environmental benefit. Because the primary environmental benefit for the regional airshed is associated with reductions in criteria pollutants, the benefit of reducing toxic air pollutants was not quantified.

No ERCs are being sought for the proposed project. The analysis of the environmental and health impact of emissions from the project was performed without taking into account reductions resulting from the removal of the refinery boilers. These reductions were considered only in a semi-quantitative manner regarding the regional impact of the project as a whole. All impact analyses required by state and federal regulation were performed without including the refinery reductions.

[1] See http://www.nwair.org/regulated/aop/BP/BP%20-%20Consent%20Decree%201-01.pdf

Responses to Comments in Letter 18 from Karen Kloempken, Fish and Wildlife Biologist, Department of Fish and Wildlife

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. In Section 3.7.2 of the Final EIS under the heading Wildlife and Habitat, Custer-Intalco Transmission Line No. 2, the following text will be added, “Bonneville will consult with WDFW during design of the transmission line to develop the Hydraulic Project Approval.”

2. In Section 3.7.1 of the Final EIS under the heading Threatened and Endangered Species, Federally Listed Threatened Species, the following text will be added, “The WDFW Priority Habitat and Species database identifies a bald eagle nesting site within about 400 feet of the Custer-Intalco Transmission Line No. 2.”

   In Section 3.7.5, Mitigation Measures, the following text will be added to the Final EIS: “Bonneville will avoid transmission line construction and maintenance activities near the known bald eagle nesting site from mid-March to mid-June.”

3. Thank you for your comment. Seed mixes in disturbed areas will be determined based on coordination with federal, state, and local agencies.

Responses to Comments in Letter 19 from Trina Blake, NW Energy Coalition

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. According to a Settlement Agreement between the Applicant and Counsel for the Environment, and should the project be approved by the Governor, the Applicant shall decommission the BP Refinery's No. 1, No. 2, and No. 3 boilers within six months of the project's entry into commercial operation. Upon completion of the decommissioning, the Applicant would provide EFSEC with written notification and proof that the boilers have been decommissioned at the BP Refinery. Other stipulations of the agreement have been included in the Final EIS, Section 3.2, Mitigation Measures.

2. Without an applicable state or federal regulation requiring mitigation or reduction of CO_2 emissions[2], the EFSEC must consider proposals for CO_2 mitigation on a case-by-case basis. According to the Settlement Agreement between the Applicant and the Counsel for the Environment, BP West Coast Products, LLC will go beyond the mitigation proposal presented in the Draft EIS. Regarding the potential for facility ownership to change, the Settlement Agreement requires that the Applicant continue to offset its ownership (equity) share of the CO_2 emissions according to BP's existing, voluntary policy, and that the third party certificate holder mitigate its share according to the requirements of the Settlement Agreement described in Section 3.2.7 of the Final EIS.

3. Capacity factor is no longer a consideration in determining the amount of CO_2 emissions that have to be mitigated. If the Applicant holds an equity (ownership) interest in the project, the Applicant will offset its share in the project's emissions by reducing greenhouse gas emissions elsewhere in the Applicant's worldwide operations, consistent with its voluntary corporate policy. If a portion of the project is sold, 23% of actual emissions would be mitigated.

4. The Settlement Agreement between Applicant and the Counsel for the Environment is independent of the Oregon standard. Depending on the ownership of the project, from 23% to 100% of actual emissions must be mitigated at a cost of $0.87 per metric ton of CO_2.

5. Through the Settlement Agreement between the Applicant and the Counsel for the Environment, the payment would be increased to $0.87 per metric ton. Although the Settlement Agreement continues to endorse annual payment, the cost per metric ton is now linked to the Producer Price Index and would be adjusted annually.

[2] House Bill 3141, signed into law on March 30, 2004, applies to proposals that submit Applications for Site Certification to EFSEC after July 1, 2004.

6. Thank you for your comment. The Settlement Agreement between the Applicant and the Counsel for the Environment does not require additional payment for administrative costs.

7. The Settlement Agreement between the Counsel for the Environment and the Applicant allows a third party (should project ownership change in the future) to choose the method of mitigation only on the share of emissions not owned by the Applicant.

8. Thank you for your comment. The Settlement Agreement between the Applicant and the Counsel for the Environment goes beyond the original proposal made by the Applicant in its Application for Site Certification and ensures substantial mitigation of CO_2 emissions.

Responses to Comments in Letter 20 from Mike Torpey, Environmental Team Lead, BP Cherry Point Cogeneration Project

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment. The description of the No Action Alternative has been revised in the Final EIS. The No Action Alternative indicates that in order to meet long term regional power needs additional generation would need to be brought on line. Baseload generation would most likely be augmented by increasing the size of existing facilities or constructing new ones. It is correct that the siting of other cogeneration facilities is less likely, because in addition to access to transmission and natural gas supply services, a cogeneration developer would have to find a receptive host for produced steam. Because non-cogeneration combustion turbine projects are less fuel efficient, they would likely produce more emissions (air and water) per kilowatt hour. The impacts of this type of inefficiency have been assigned to the No Action Alternative in the respective sections of Chapter 3.

   Appropriate changes/corrections have been incorporated into the Final EIS. The project description in the Draft EIS was consistent with the Application for Site Certification and its Appendix D; therefore, the “typographical errors or correcting statements” usually reflect changes in the design of the project since the Draft EIS was prepared.

3. See specific responses below.

3(1) Thank you for your comment. The Draft EIS has been revised to reflect an 83% boiler efficiency.

3(2) Thank you for your comment. The Draft EIS has been revised to note the Bonneville right-of-way occupies 71 acres.

3(3) Thank you for your comment. A 265-horsepower, diesel-driven emergency water pump for fire suppression has been added to the list of project elements.

3(4) Thank you for your comment. Treatment facilities for boiler water have been added to the list of project elements.

3(5) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description.

3(6) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description.

3(7) Please refer to Response 2 of this letter.

3(8) Thank you for your comment. This and the following six comments relate to “issues to be resolved.” Section 1.6.1 of the Draft EIS has been revised to reflect the resolution of this issue.

3(9) Thank you for your comment. The Draft EIS has been revised to reflect the resolution of this issue and change in the project description.

3(10) Thank you for you comment. Table 2-1 of the Draft EIS has been revised to reflect this change in the project description.

3(11) Thank you for you comment. Table 2-1 of the Draft EIS has been revised to reflect this change in the project description.

3(12) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description. The new substation within the refinery near the existing substation MS3 will have a kilovolt capacity of 115, not 230 kV.

3(13) Thank you for you comment. The Draft EIS has been revised to reflect this refinement of the project description. Wetland impacts from the construction of the pipeline support structure are addressed in the Section 3.5, Wetlands, of the Final EIS.

3(14) Thank you for your comment. The commenter notes the expansion or modification to the Custer-Intalco electrical transmission system will be built, owned, and operated by Bonneville. The types of transmission structures to be erected are identified in Figure 1-2 and described in Section 2.2.2 of the Draft EIS. The following sentence has been inserted in the Final EIS under the heading Option 2b - New Transmission Line with Monopole Towers, “Under either Option 2a or 2b, the specific number of structures and their locations, as well as specific access road needs, will not be known until further design is completed.”

3(15) The bullet has been revised to reflect mitigation measures presented in the revised Application for Site Certification.

3(16) Thank you for your comment.

3(17) Table 1-2 of the Draft EIS has been revised to reflect this addition.

3(18) Thank you for your comment.

3(19) Thank you for your comment. According to the Stormwater Management Manual for Western Washington (Ecology 2000), Best Management Practice (BMP) C106 recommends the use of wheel washers for construction sites when a stabilized construction entrance is not preventing sediment from being tracked onto pavement.

3(20) Thank you for your comment.

3(21) Table 1-2 of the Draft EIS as been revised to reflect this addition.

3(22) Thank you for your comment.

3(23) Thank you for your comment. The recommended mitigation measure has been incorporated into list of the Applicant's proposed mitigation measures.

3(24) The EIS has been revised to reflect this correction.

3(25) For information on the agreed upon traffic mitigation after the start of construction, please refer to Letter 8, Response 1.

3(26) The existence of the 71-acre Bonneville right-of-way as part of the project has been noted in the Final EIS.

3(27) Thank you for your comment. The pump has been added to the equipment list for the cogeneration facility in the Final EIS.

3(28) Thank you for your comment. Water treatment facilities have been added to the referenced list.

3(29) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(30) Thank you for your comment. The Draft EIS has been revised to reflect this change in the list of proposed equipment.

3(31) Thank you for your comment. Table 2-1 of the Draft EIS has been revised to reflect uninterruptible power supply.

3(32) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(33) Thank you for your comment.

3(34) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(35) The Draft EIS has been revised to reflect this clarification. Conditions set through the National Pollutant Discharge Elimination System (NPDES) permit, BMPs, and other permit requirements are expected to protect state water quality standards by limiting potential contamination of stormwater and protecting groundwater quality during construction and operations.

3(36) Thank you for your comment. According to the draft NPDES permit, “stormwater that has the potential to collect process chemicals and lube oils will be routed to the process wastewater system.”

3(37) Section 2.2.2, Project Description, and Section 3.3.2 of the Draft EIS have been revised to reflect this additional information.

3(38) The Draft EIS has been revised to reflect that Compensatory Mitigation Area (CMA) 2 will receive stormwater discharge from the cogeneration facility.

3(39) BP’s application indicates that Access Road 3 would meet Washington State Department of Transportation (WSDOT) and emergency vehicle requirements. According to Section 2.11 of Appendix D in the application, roadwork outside the plant boundary would be constructed in accordance with the WSDOT and emergency vehicle requirements. The Applicant did not support the suggested change in Access Road 3 construction standards with a revision to the application or a commitment during the adjudicative hearings.

3(40) Thank you for your comment. The text in the Draft EIS has been revised to reflect that all major equipment and buildings, including the steam generator, will be on piles.

3(41) Section 2.2.3 of the Draft EIS has been revised to reflect this new information.

3(42) Section 2.2.3 of the Draft EIS has been revised to reflect this new information.

3(43) Section 2.2.3 of the Draft EIS has been revised to reflect that the right-of-way will not exceed 150 feet in width.

3(44) Section 2.2.4 of the Draft EIS has been revised to reflect this clarification.

3(45) Thank you for your comment. The EIS has been revised to reflect this information.

3(46) The Draft EIS has been revised to more accurately reflect the Application for Site Certification’s mitigation requirements if contaminated soils are found during construction.

3(47) Table 3.2-1 of the Draft EIS has been revised to reflect this clarification.

3(48) Table 3.2-1 of the Draft EIS has been revised to reflect this clarification.

3(49) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(50) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(51) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(52) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(53) Section 3.2 of the Draft EIS has been updated to reflect that no criteria pollutant emission concentrations exceed the Class II Significant Impact Levels (SILs).

3(54) Section 3.2 in the Final EIS has been updated to reflect that no criteria pollutant emission concentrations exceed the Class I SILs.

3(55) The discussion of estimated emissions from the project, including emission reductions resulting from refinery boiler removal and other adjustments, has been revised for more clarity. The correction has been made.

3(56) Secondary particulate conversions based on molecular weights have been incorporated into Section 3.2.

3(57) The Final EIS reflects the statement in the Application for Site Certification (Volume 1, Section 3.2.3.2) that, "icing is not expected to occur."

3(58) The Draft EIS has been revised to state that, excluding those projects that have received certification from EFSEC, no currently permitted facilities are subject to greenhouse gas mitigation requirements in Washington State.

3(59) The No Action Alternative in Section 3.2 of the Draft EIS has been revised to reflect that if other natural gas–fired plants are built to meet regional electric demand, they would not likely be cogeneration facilities and would likely produce energy less efficiently than the proposed project. This would result in higher criteria pollutant and greenhouse gas emissions per kilowatt hour produced.

3(60) Please refer to Response 3(59) of this letter. The tonnage of CO_2 emission reductions was corrected in the Final EIS.

3(61) The Department of Energy (DOE) recognizes that natural gas leaks occur in natural gas transmission systems. The Final EIS estimates the resulting greenhouse gas emissions that could occur based on the DOE emission factors.

3(62) The Phase I study (Bonneville 2001a) went as far as identifying where impacts might occur in the northwest region assuming all the facilities considered became operational. The Phase I study did not attempt to identify which facilities caused the potential impacts identified. The purpose of the Phase II study for each specific project being proposed (i.e., the BP Cherry Point Cogeneration Project) was to refine the analysis of regional impacts and determine to what degree the impacts could be attributable to that specific facility. As indicated in the Final EIS, the Phase II study conducted for the proposed cogeneration project concluded that the project would not significantly contribute to regional haze at any of the Class I areas within the Bonneville service area, the Columbia River Gorge National Scenic Area, or the Mt. Baker Wilderness when the facilities considered in this analysis are fired by natural gas. During periods of oil firing during a winter simulation by other facilities in the study group, the project's contributions are not significant on any of the six days when the baseline group's combined change in extinction is greater than 10% in Mt. Rainier National Park. (Extinction is a coefficient used to quantify how pollutants in the atmosphere reduce visual range.)

3(63) Thank you for your comment. The correction has been made in Section 3.2 of the Final EIS.

3(64) Please refer to Response 3(62) of this letter.

3(65) The statement has been revised to reflect that the production of greenhouse gases could be reduced if operation of the BP Cogeneration Facility displaces the operation of other less efficient facilities that emit more greenhouse gases per kilowatt-hour.

3(66) Table 3.2-28 has been revised to reflect this clarification.

3(67) Table 3.2-29 has been revised to reflect this clarification.

3(68) Table 3.2-29 has been revised to reflect this clarification.

3(69) The mitigation measure has been revised in the Final EIS.

3(70) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(71) Section 3.2.8 of the Draft EIS has been revised to reflect that the proposed cogeneration facility would have a minimal impact on air quality and would not violate any ambient air quality standards or objectives, or other regulatory air quality values.

3(72) Thank you for your comment. According to the Stormwater Management Manual for Western Washington (Ecology 2000), Best Management Practice C162 specifically recommends avoiding land disturbance activities during rainy periods.

3(73) Please refer to Response 3(72) of this letter.

3(74) Based on the contour information available at this time, it appears the project will intercept the low spot in the wetland. Using the 1-foot contours to fine tune the ditch design is a good first step. It is the opinion of the Corps of Engineers that there should be no perimeter ditch within the wetland or buffer to minimize the potential for draining Wetland C (Romano, pers. comm., 2004).

3(75) The text of the Draft EIS has been revised to reflect this correction.

3(76) The application indicates sanitary waste discharge from the cogeneration project would be routed to the PUD's wastewater treatment plant for treatment and discharge to the Strait of Georgia. The Applicant did not support this suggested change with a revision to the application or a commitment during the adjudicative hearings.

3(77) Thank you for your comment. The Draft EIS has been revised to reflect this clarification. Please refer also to Response 3(35) of this letter.

3(78) The text of the Draft EIS has been revised to reflect this correction.

3(79) A map provided by Whatcom County (Olson, pers. comm., 2004) depicts most of the western half of Section 8 (east of Blaine Road between Grandview and Aldergrove) as “open space agriculture.” This would include the refinery interface area. This is not a zoning designation, but rather a Department of Revenue designation for current use taxation valuation.

3(80) The text of the Draft EIS has been revised to reflect this correction.

3(81) The text of the Draft EIS has been revised to reflect this correction.

3(82) Comment acknowledged. As noted in Section 3.4.4.2 of the revised Application for Site Certification, “all equipment should be cleaned before leaving the site.” The Draft EIS text was revised to read, “to minimize and control the spread of noxious weed species, all-wheeled vehicles would be cleaned if they cross disturbed or exposed soil areas during construction of the proposed project.”

3(83) The Draft EIS has been revised to reflect that a person’s perception of a 3- to 5-dBA change in noise levels may vary with the environmental context.

3(84) The commenter is correct, and the statement in Section 3.9-6 of the Draft EIS has been removed.

3(85) The commenter is correct, and Table 3.9-5 of the Draft EIS has been revised.

3(86) The construction mitigation measure list has been revised.

3(87) The construction mitigation measure list has been revised.

3(88) Thank you for your comment. The correction has been made in the Final EIS.

3(89) The text of the Draft EIS has been revised to reflect this correction.

3(90) The Corps of Engineers and the State Historic Preservation Office (SHPO) concur with the results of the archaeological survey conducted near detention pond 2, the interconnecting pipeway, and Access Road 3. In a letter to the Corps, SHPO agreed with the definition of the Area of Potential Effect (APE) and concurred with the Corps’ recommendation of Finding of No Historic Properties.

In conformance with Section 106 of the National Historic Preservation Act, the Corps identified and listed conditions in its 404 permit. SHPO also concurred with these conditions, which the Applicant would be required to comply with during construction of the proposed project.

3(91) The commenter is correct. Note 2 has been corrected in the Final EIS.

3(92) The text of the Draft EIS has been revised to reflect this correction.

3(93) The text of the Draft EIS has been revised to reflect this correction.

3(94) The text of the Draft EIS has been revised to reflect this correction

3(95) The text of the Draft EIS has been revised to reflect this correction.

3(96) Thank you for your comment. Although the use of waterborne transportation (barge) to bring heavy equipment to the site was identified in the Application for Site Certification, correspondence dated May 30, 2003, from the Applicant specifically states a barge would not be used. Therefore, the Applicant does not address potential landing impacts in the nearshore, road impacts from heavy equipment, road conflicts on public roads, or other issues. According to the Applicant, barge landings would require a number of authorizations for which analyses have not been produced. At this time, barge transport of equipment is not considered viable.

3(97) The text of the Draft EIS has been revised to reflect this correction.

3(98) The text of the Draft EIS has been revised to reflect this correction. Please refer to Response 3(25) of this letter.

3(99) Reference to the Health and Safety Plan and the Emergency and Security Plan has been revised.

3(100) The text of the Draft EIS has been revised to reflect this correction.